# UTAH DIVISION OF AIR QUALITY
# SOURCE PLAN REVIEW

Michelle Bujdoso
Tesoro Refining and Marketing Company
474 W 900 N
Salt Lake City, UT 84103

Project Number: N103350062

| | |
|---|---|
| RE: | Gasoline Hydrotreater Conversion Project to Include Kerosene Service as New Method of Operation<br>Salt Lake County; CDS A; MACT (Part 63), Nonattainment or Maintenance Area, Title V (Part 70) major source, $PM_{10}$ SIP / Maint Plan, Major criteria source, Title V (Part 70), NESHAP (Part 61), Major HAP source, NSPS (Part 60), |
| Review Engineer: | John Jenks |
| Date: | May 15, 2013 |
| Notice of Intent Submitted: | November 29, 2012 |
| Plant Contact: | Michelle Bujdoso |
| Phone Number: | (801) 366-2036 |
| Fax Number: | (801) 521-4965 |
| Source Location: | 474 West 900 North, Salt Lake City, UT<br>Salt Lake County<br>4,515,950 m Northing, 423,400 m Easting, UTM Zone 12<br>UTM Datum: NAD27 |

DAQ requests that a company/corporation official read the attached draft/proposed Plan Review with Recommended Approval Order Conditions. If this person does not understand or does not agree with the conditions, the review engineer should be contacted within five days after receipt of the Plan Review. If this person agrees with the Plan Review and Recommended Approval Order Conditions, this person should sign below and return (FAX # 801-536-4099) within 10 days after receipt of the conditions. If the review engineer is not contacted within 10 days, the review engineer shall assume that the company/corporation official agrees with this Plan Review and will process the Plan Review towards final approval. A public comment period will be required before the Approval Order can be issued.

Applicant Contact ____________________________________________________________
*(Signature & Date)*

**OPTIONAL:** In order for this Source Plan Review and associated Approval Order conditions to be administratively included in your Operating Permit (Application), the Responsible Official as defined in R307-415-3, must sign the statement below and the signature above is not necessary. THIS IS STRICTLY OPTIONAL!

If you do not desire this Plan Review to be administratively included in your Operating Permit (Application), only the Applicant Contact signature above is required. Failure to have the Responsible Official sign below will not delay the Approval Order, but will require a separate update to your Operating Permit Application or a request for modification of your Operating Permit, signed by the Responsible Official, in accordance with R307--415-5a through 5e or R307-415-7a through 7i.

> **"Based on reasonable inquiry, I certify that the information provided for this Approval Order has been true, accurate and complete and request that this Approval Order be administratively amended to the Operating Permit (Application)."**

Responsible Official ______________________________________________

(Signature & Date)

Print Name of Responsible Official ____________________________________

## ABSTRACT

On November 29, 2012, Tesoro Refining and Marketing Company submitted a NOI for a Gasoline Hydrotreater Conversion Project to Include Kerosene Service as a New Method of Operation. An addendum to this NOI was submitted on February 5, 2013 to amend condition II.B.3.a of Tesoro's existing AO. Tesoro requested that when amended, the new condition be included in the Kerosene Service Method of Operation proposal.

The project converts the method of operation of the gasoline hydrotreater from gasoline production to jet kerosene as desired. This will require installation of piping, temperature and process controls, and some physical modifications at the reboiler. Both the GHT Reactor Charge Heater and DDU Charge Heaters will increase firing rates, but will not be physically modified. The increase in firing rates does not constitute a modification at these units as they are already capable of firing at these rates and are not operationally or permit limited. The SRU will process approximately 470 lb per day of additional sulfur from the DDU. Some storage tanks and the loading rack will have increased throughput of kerosene and distillate fuel oil.

Tesoro's refinery is located in Salt Lake City, Salt Lake County, which is a nonattainment area for $PM_{10}$, $PM_{2.5}$ and $SO_2$, and a maintenance area for ozone and CO. Tesoro is subject to federal NSPS, NESHAP and MACT requirements, and is defined as a major contributing source in the $PM_{10}$ SIP. The $PM_{10}$ SIP has established emission caps for $PM_{10}$, $SO_2$ and $NO_x$ which shall remain at their present values. This project is classified as a minor modification. Expected increases in actual emissions are estimated at the following ton per year values: $PM_{10}$: 0.13, $PM_{2.5}$ (a subset of $PM_{10}$): 0.13, $NO_x$: 1.28, $SO_2$: 8.99, CO: 1.47, VOC: 2.0, $CO_2$e: 2,390. Estimates of actual HAP emissions are expected to increase by 328 lb/yr, with the largest expected component being xylene at approximately 181 lb/yr. Total PTE from the entire refinery is estimated at the following tons per year values: $PM_{10}$ = 282, $PM_{2.5}$ (a subset of $PM_{10}$) = 154, $NO_x$ = 638, $SO_2$ = 1637, CO = 1,376, VOC = 793. Tesoro is a major source of HAPs and GHG emissions.

## SOURCE SPECIFIC DESIGNATIONS

**Applicable Programs:**

NSPS (Part 60), Subpart A: General Provisions applies to Permitted Source

NSPS (Part 60), Subpart Db: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units applies to Permitted Source

NSPS (Part 60), Subpart J: Standards of Performance for Petroleum Refineries applies to Permitted Source

NSPS (Part 60), Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to Permitted Source

NSPS (Part 60), Subpart K: Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978 applies to Permitted Source

NSPS (Part 60), Subpart Ka: Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984 applies to Permitted Source

NSPS (Part 60), Subpart Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels

(Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 applies to Permitted Source
NSPS (Part 60), Subpart GG: Standards of Performance for Stationary Gas Turbines applies to Permitted Source
NSPS (Part 60), Subpart XX: Standards of Performance for Bulk Gasoline Terminals applies to Permitted Source
NSPS (Part 60), Subpart GGG: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006 applies to Permitted Source
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to Permitted Source
NSPS (Part 60), Subpart NNN: Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations applies to Permitted Source
NSPS (Part 60), Subpart QQQ: Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems applies to Permitted Source
NESHAP (Part 61), Subpart A: General Provisions applies to Permitted Source
NESHAP (Part 61), Subpart M: National Emission Standard for Asbestos applies to Permitted Source
NESHAP (Part 61), Subpart FF: National Emission Standard for Benzene Waste Operations applies to Permitted Source
MACT (Part 63), Subpart A: General Provisions applies to Permitted Source
MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Permitted Source
MACT (Part 63), Subpart UUU: National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units applies to Permitted Source
MACT (Part 63), Subpart EEEE: National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline) applies to Permitted Source
MACT (Part 63), Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters applies to Permitted Source
Major HAP source applies to Permitted Source
Major criteria source applies to Permitted Source
$PM_{10}$ SIP / Maint Plan applies to Permitted Source
Title V (Part 70) applies to Permitted Source
Title V (Part 70) major source applies to Permitted Source
Salt Lake City CO Maintenance Area applies to Permitted Source
Salt Lake County O3 Maintenance Area applies to Permitted Source
Salt Lake County $PM_{10}$ NAA applies to Permitted Source
Salt Lake County $PM_{2.5}$ NAA applies to Permitted Source
Salt Lake County $SO_2$ NAA applies to Permitted Source

**Permit History:**

When issued, the approval order shall supersede or will be based on the following documents:

| | |
|---|---|
| Is Derived From | Source Submitted NOI dated November 29, 2012 |
| Incorporates | Additional Information Submitted dated February 5, 2013 |
| Supersedes | DAQE-AN103350058B-13 dated February 12, 2013 |

**Nonattainment or Maintenance Areas Impacted:**

Salt Lake City CO Maintenance Area
Salt Lake County O3 Maintenance Area
Salt Lake County $PM_{10}$ NAA
Salt Lake County $PM_{2.5}$ NAA
Salt Lake County $SO_2$ NAA

## SUMMARY OF NOTICE OF INTENT INFORMATION

**Description of Proposal:**

The project converts the method of operation of the gasoline hydrotreater from gasoline production to jet kerosene as desired. This will require installation of piping, temperature and process controls, and some physical modifications at the reboiler. Both the GHT Reactor Charge Heater and DDU Charge Heaters will increase firing rates, but will not be physically modified. The increase in firing rates does not constitute a modification at these units as they are already capable of firing at these rates and are not operationally or permit limited. The SRU will process approximately 470 lb per day of additional sulfur from the DDU. Some storage tanks and the loading rack will have increased throughput of kerosene and distillate fuel oil.

Reactor effluent will be used as the stabilizer reboil medium rather than steam, resulting in lowering of the feed/effluent heat exchanger duty. Secondly, a pump will be installed to move kerosene product to tankage. Additional distillate fuel oil #2 will be produced and blended with jet kerosene.

Condition II.B.3.a will be modified so that gaseous emissions from the SRU will be treated by the TGTU during normal operations prior to treatment at the TGI.

**Summary of Emission Totals:**

The emissions listed below are an estimate of the total potential emissions from the source. Some rounding of emissions is possible.

| Estimated Criteria Pollutant Potential Emissions | | |
|---|---|---|
| $CO_2$ Equivalent (project only actual emission increases) | 2860.90 | tons/yr |
| Carbon Monoxide | 1376.00 | tons/yr |
| Nitrogen Oxides | 638.00 | tons/yr |
| Particulate Matter - $PM_{10}$ | 282.00 | tons/yr |
| Particulate Matter - $PM_{2.5}$ | 154.00 | tons/yr |
| Sulfur Dioxide | 1637.00 | tons/yr |
| Volatile Organic Compounds | 793.00 | tons/yr |

| Estimated Hazardous Air Pollutant Potential Emissions | | |
|---|---|---|
| Total hazardous air pollutants (project only actual emission increase) | 2.36 | tons/yr |

**Review of Best Available Control Technology:**

1. BACT review regarding BACT Review
   The application of BACT (or LAER) is triggered in two instances.

   The first occurs when a source must apply BACT or LAER when federally required to do so. This would be the case when a source has triggered a new major source or major modification provision. This project does not qualify as either a new major source or major modification under either the federal PSD or federal nonattainment NSR rules. Therefore BACT/LAER is not required under these circumstances.

   The second instance falls under R307-401-5(d), which permits the issuance of an AO if it is determined that the pollution control for emissions is at least BACT. This is only required for new emission units or existing emission units where there is both a physical change and an increase in emissions.

   Therefore a BACT review is not required for the GHT Process Heater (F-701), DDU Charge Heater (F-680), SRU, storage tanks or loading rack as these units are not being phyically modified. A BACT review is required for the new components added as a part of this project.

   As these components are all fugitive VOC related (piping, valves, pumps, etc), DAQ has routinely shown that good operational practices constitute BACT for these types of emissions. Tesoro is required to comply with a Consent Decree which requires stringent VOC monitoring through a "low leak" LDAR (leak detection and repair) program. DAQ submits that this program continues to represent BACT. [Last updated May 15, 2013]

**Modeling Results:**

This project does not increase any of the existing permit limits and no other changes are being made with respect to overall SIP cap emissions. This project is considered a minor modification under both PSD and nonattainment area NSR. The source is regulated under existing MACT standards and the anticipated increases in actual HAP emissions are not required to be modeled as outlined in R307-410-5(1)(a)(i). Therefore no modeling is required. [R307-403, R307-405, R307-410]

[Last updated May 15, 2013]

## RECOMMENDED APPROVAL ORDER CONDITIONS

The intent is to issue an air quality Approval Order (AO) authorizing the project with the following recommended conditions and that failure to comply with any of the conditions may constitute a violation of the AO. The AO will be issued to and will apply to the following:

| **Name of Permittee:** | **Permitted Location:** |
|---|---|
| Tesoro Refining and Marketing Company<br>474 W 900 N<br>Salt Lake City, UT 84103 | Salt Lake City Refinery<br>474 West 900 North<br>Salt Lake City, UT 84103 |

**UTM coordinates:** 423,400 m Easting, 4,515,950 m Northing, UTM Zone 12
**SIC code:** 2911 (Petroleum Refineries)

### Section I: GENERAL PROVISIONS

I.1 All definitions, terms, abbreviations, and references used in this AO conform to those used in the UAC R307 and 40 CFR. Unless noted otherwise, references cited in these AO conditions refer to those rules. [R307-101]

I.2 The limits set forth in this AO shall not be exceeded without prior approval. [R307-401]

I.3 Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved. [R307-401-1]

I.4 All records referenced in this AO, which are required to be kept by the owner/operator, shall be made available to the Director or Director's representative upon request, and the records shall include the two-year period prior to the date of the request. Records shall be kept for a minimum of five (5) years. Records for the Consent Decree, Civil Action No. 2:96 CV 095 RL shall be kept for the life of the Consent Decree. [R307-415-6a]

I.5 A. The owner/operator shall comply with R307-150 Series. Inventories, Testing and Monitoring.

B. The owner/operator shall maintain records of annual actual emissions of $NO_x$, $SO_2$, VOC, and $H_2SO_4$ on a calendar year basis in accordance with 40 CFR 52.21(r)(6) following resumption of regular operations after completion of construction of all projects listed in Condition I.7. These records will be maintained for the following emission units:

Crude Unit Furnace H-101
FCCU/CO Boiler
Ultraformer Unit Furnace F-1
UFU Regeneration Heater F-15
DDU Charge Heater F-680
DDU Rerun Boiler F-681
SRU/TGTU/TGI
GHT Unit F-701
Ultraformer Compressors K1s
Cogeneration Unit Turbines

Cogeneration Unit HRSGs
DDU Reactor (SSM events)
VRU Vessels (SSM events)
FGDU/SWS (SRU) Flare
Cooling Tower UU3
LPG Rack
Gasoline and DieselTruck Loadout Rack
Storage Tanks (186, 188, 204, 212, 213, 242, 243, 252, 321, 324, 325, 326, 327, 330, 331, 503, 504)
New and Replaced Components

C. Should the total actual annual emissions of $SO_2$ on a 12-month rolling basis from emission units associated with the project exceed the value listed below, during the interim period beginning from the date that regular operations resume after completion of the first phase until the date that regular operations begin following the second phase of construction of the projects listed in Condition I.7, the owner/operator shall submit an emission report within 60 days of the exceedance. The report shall contain the following:

( a ) The name, address and telephone number of the major stationary source;
( b ) The annual emissions as calculated; and
( c ) Any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

| | |
|---|---|
| Crude Unit Furnace H-101 | 5.54 tpy |
| FCCU/CO Boiler | 645.38 tpy |
| Ultraformer Unit Furnace F-1 | 5.16 tpy |
| UFU Regeneration Heater F-15 | 0.30 tpy |
| DDU Charge Heater F-680 | 1.01 tpy |
| DDU Rerun Boiler F-681 | 0.84 tpy |
| SRU/TGTU | 399.42 tpy |
| GHT Unit F-701 | 0.28 tpy |
| Ultraformer Compressors K1s | 0.01 tpy |
| Cogeneration Unit Turbines | 0.63 tpy |
| Cogeneration Unit HRSGs | 6.47 tpy |
| DDU Reactor (SSM events) | 0.00 tpy |
| VRU Vessels (SSM events) | 0.00 tpy |
| Significant Emission Rate (Additional Allowed Emissions) | 40 tpy |
| Total Emissions | 1,105.03 tpy |

[R307-150, R307-405-19]

I.6 The owner/operator shall comply with UAC R307-107. General Requirements: Breakdowns. [R307-107]

I.7 Tesoro shall notify the Director in writing within 30 days after the new spray tower, $CONO_x$ project, FCCU overhead condensing project, and the Waxy Crude Processing Project are installed and operational, as an initial compliance inspection is required. To ensure proper credit when notifying the Director, send your correspondence to the Director, attn: Compliance Section.

Approval orders issued by the Director in accordance with the provisions of R307-401 will be reviewed eighteen months after the date of issuance to determine the status of construction, installation, modification, relocation or establishment. If a continuous program of construction, installation, modification, relocation or establishment is not proceeding, the Director may revoke the approval order. If installation of the Waxy Crude Processing Project has not been completed within 18 months of issuance of this AO, the Director shall be notified in writing on the status of the installation. If an eighteen month period of inactivity in construction/installation of the BenSat Unit, LPG Recovery Project, UFU Scrubber or the PDO rerouting project is anticipated, the Director shall be notified as outlined in R307-401-18.

Tesoro shall submit an interim report within 60 days following resumption of regular operations after completion of Phase 1 of this project. This report shall detail the status of construction of each project listed above, and the expected date of beginning construction of Phase 2 of these projects. [R307-401-18, R307-405-19]

## Section II: SPECIAL PROVISIONS

**II.A The approved installations shall consist of the following equipment:**

II.A.1 **Permitted Source**
Permitted Source

II.A.2 **H-101**
Crude Unit Furnace, with ultra-low $NO_x$ burners and one (1) stack, PS #1

II.A.3 **F-1**
Ultraformer Unit (UFU) Furnace, with low $NO_x$ burners and four (4) stacks, PS #2

II.A.4 **F-15**
UFU Regeneration Heater, with low $NO_x$ burners and one (1) stack, PS #3

II.A.5 **FCCU/CO Boiler**
Fluid catalytic Cracking Unit (FCCU) Regenerator, Carbon Monoxide Boiler (Heat Recovery Unit), with $CONO_x$ oxygen injection, ammonia injection, electrostatic precipitator (ESP) and one (1) stack, PS #4

II.A.6 **F-680 and F-681**
Distillate Desulfurization Unit (DDU) charge heater and rerun boiler, combined rating approx. 37.8 MMBtu/hr, equipped with "ultra-ultra" low $NO_x$ burners. Heaters share common convection section and stack, PS #5.

II.A.7 **K1s**
Hydrogen Compressors (Ultraformer compressors), with catalytic converters and two (2) stacks, PS #6

II.A.8 **South Flare**
Flare covering Crude/UFU Unit/DDU, PS #7

II.A.9 **North Flare**
Flare covering FCCU/VRU/Alkylation Unit/GHT, PS #8

II.A.10 **CO Boiler Bypass**
CO Boiler Bypass, with quench system and routed to FCCU ESP, with one (1) stack, PS #9

II.A.11 **SRU/TGI/TGTU**
Sulfur Recovery Unit/Tail Gas Incinerator/Tail Gas Treatment Unit, PS #10

II.A.12 **FGDU/SWS**
Fuel Gas Desulfurization Unit/Sour Water Stripper (FGDU/SWS) Flare (this unit is physically integrated with the Sulfur Recovery Unit (SRU)), PS #11

II.A.13 **T-104**
Sour Water Storage Tank

II.A.14 **Emergency/Standby Sources**
Waste Water Treatment Plant (WWTP) Generator, Electrical Generators, Plant Air Compressors, Miscellaneous Air Compressors, Fire Water Pumps, B-1 Air Preheater, Package Boilers

II.A.15 **F-701**
Gasoline Hydrotreater (GHT) Unit with 8.0 MMBtu/hr process heater

II.A.16 **BSU**
Benzene Saturation Unit (BSU):
3,000 bpd Bensat reactor and 10,000 bpd reformate splitter.

II.A.17 **CG1 and CG2**
Cogeneration Unit: two cogeneration trains (CG1 and CG2), each with one 11.8 MW (based on an annual average) turbine with $SoLoNO_x$ controls and one heat recovery steam generating

unit rated at approx 157.8 MMBtu/hr (HHV). Both rates based on an annual average.

II.A.18 **Loading/Unloading Racks**

II.A.19 **Tank 140: Storage vessel - petroleum liquids**
Storage tank with internal floating roof and primary seals

II.A.20 **Tank 141: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.21 **Tank 142: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.22 **Tank 144: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.23 **Tank 157: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.24 **Tank 158: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.25 **Tank 186: Storage vessel - petroleum liquids**
Storage tank with internal floating roof, primary and secondary seals

II.A.26 **Tank 188: Storage vessel - petroleum liquids**
Storage tank with internal floating roof, primary and secondary seals

II.A.27 **Tank 189: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.28 **Tank 190: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.29 **Tank 201: Storage vessel - amine**
Storage tank with fixed roof

II.A.30 **Tank 203: Storage vessel - stormwater**
Storage tank with fixed roof

II.A.31 **Tank 204: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.32 **Tank 206: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.33 **Tank 212: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.34 **Tank 213: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.35 **Tank 236: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.36 **Tank 241: Storage vessel - surge tank**
Storage tank with external floating roof, primary and secondary seals

II.A.37 **Tank 242: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.38 **Tank 243: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.39 **Tank 244: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.40 **Tank 245: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.41 **Tank 246: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.42 **Tank 247: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.43 **Tank 252: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.44 **Tank 270: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.45 **Tank 271: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.46 **Tank 291: Storage vessel - petroleum liquids**
Storage tank with fixed roof to be retrofitted with internal floating roof

II.A.47 **Tank 297: Storage vessel - petroleum liquids**
Storage tank with internal floating roof and primary seals

II.A.48 **Tank 298: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.49 **Tank 307: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.50 **Tank 308: Storage vessel - chemicals**
Storage tank with external floating roof, primary and secondary seals

II.A.51 **Tank 309: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.52 **Tank 310: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.53 **Tank 311: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.54 **Tank 312: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.55 **Tank 313: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.56 **Tank 314: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.57 **Tank 315: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.58 **Tank 321: Storage vessel - petroleum liquids**
Storage tank with internal floating roof and primary seals

II.A.59 **Tank 322: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.60 **Tank 323: Storage vessel - petroleum liquids**
Storage tank with fixed roof

II.A.61 **Tank 324: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.62 **Tank 325: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.63 **Tank 326: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.64 **Tank 327: Storage vessel - gasoline**
Storage tank with external floating roof, primary and secondary seals, and slotted guide pole controls

II.A.65 **Tank 328: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.66 **Tank 330: Storage vessel - petroleum liquids**
Storage tank with external floating roof, primary and secondary seals

II.A.67 **Tank 331: Storage vessel - petroleum liquids**
Storage tank with internal floating roof, primary and secondary seals

II.A.68 **$SO_2$ Cap Sources**
Sources included in emissions cap: includes F-701, CG1 and CG2, H-101, FCCU/CO Boiler, K1s, F-1, F-15 , F-680 and F-681

II.A.69 **$NO_x$ Cap Sources**
Sources included in emissions cap: includes F-701, CG1 and CG2, H-101, FCCU/CO Boiler, K1s, F-1, F-15 , F-680 and F-681

II.A.70 **$PM_{10}$ Cap Sources**
Sources included in emissions cap: includes F-701, CG1 and CG2, H-101, FCCU/CO Boiler, K1s, F-1, F-15 , F-680 and F-681

## II.B Requirements and Limitations

II.B.1 **Conditions on Permitted Source**

II.B.1.a Visible emissions from the stacks of combustion units without controls shall be no greater than 10 percent(%) opacity. Compliance shall be determined using opacity observations performed in accordance with 40 CFR 60, Appendix A, Method 9. [R307-401]

II.B.1.b Tesoro shall limit operation of the emergency/standby package boilers listed in Section II.A.14 to an annual capacity factor of 10% (0.10) or less for natural gas as specified in 40 CFR 60 Subpart Db. [R307-401]

II.B.1.c Visible emissions from the ESP and fugitive emissions shall not exceed 20% opacity. Compliance shall be determined using opacity observations performed in accordance with 40 CFR 60, Appendix A, Method 9. Also, opacity at the ESP shall be measured by a continuous emission monitor that meets or exceeds the requirements contained in 40 CFR 60, Appendix B, and Performance Specification 1. The monitor span shall be 60% opacity. A clear stack calibration shall be performed in accordance with R307-170 as directed by the Director. 40 CFR 60 Method 9 shall be used to determine relative accuracy when required. If a new monitor is installed, an initial performance test shall be performed within 30 days of installation. The performance test shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 60, Appendix B, and Performance Specification 1. Notification must be made to the Director prior to conducting the performance test.

Visible emissions from process flares, fugitive dust, and the FCCU (when going through the bypass stack) shall not exceed 20% opacity. Compliance shall be determined using opacity observations performed in accordance with 40 CFR 60, Appendix A, Method 9.
[R307-401]

II.B.1.d Tesoro shall submit to the Director a projection of planned and required process shutdowns for the upcoming calendar year by January 15 of each year. [R307-401]

II.B.1.e Tesoro shall control the sulfur pit emissions by continuing to route sulfur pit emissions to the incinerator at the SRU. [R307-401]

II.B.1.f Tesoro shall supply no more than one-third of its potential electrical output capacity on an annual basis to any utility power distribution system for sale (on a gross basis). Records of capacity and annual electrical sales shall be maintained. [R307-401]

II.B.2 **Conditions on Crude Unit Furnace (H-101)**

II.B.2.a Emissions of $NO_x$ shall not exceed 0.054 lb/MMBtu on a 3-hour average basis.

Compliance shall be demonstrated by means of annual $NO_x$ emissions testing as directed in 40 CFR 60 Appendix A, Test Method 7, 7A, 7B, 7C, 7D or 7E.
[R307-401]

II.B.3 **Conditions on SRU/TGI/TGTU**

II.B.3.a Tesoro shall install a TGTU (tail gas treatment unit) at the SRU as part of the Waxy Crude Processing Project. Installation of the TGTU shall be complete prior to the resumption of normal operations as outlined in conditions I.5 and I.7. Gaseous emissions from the SRU shall be treated by the TGTU during normal operations prior to final treatment at the TGI. [R307-401]

II.B.3.b The $SO_2$ limit at the SRU/TGI/TGTU is 1.68 tons/day. Compliance with the daily limitation shall be determined as follows:

Daily sulfur dioxide emissions from the SRU/TGI/TGTU shall be determined by multiplying the $SO_2$ concentration in the flue gas by the mass flow of the flue gas.

Emissions of $SO_2$ from the SRU/TGI/TGTU shall not exceed 60 tons per rolling 12-month period. Compliance shall be determined on a 12-month rolling average. Within 20 days of the beginning of each calendar month, the $SO_2$ emission totals calculated to demonstrate compliance with the daily limitations shall be totaled for the previous month. The monthly total shall be added to the totals from the previous 11 months to determine the new 12-month rolling total.
[R307-401]

II.B.3.b.1 The $SO_2$ concentration in the flue gas shall be determined by a CEM that meets or exceeds the requirements contained in 40 CFR 60, Appendix B, Performance Specification 2. Daily zero (0-20% of span value) and span (50-100% of span value) calibration drift tests shall be conducted in accordance with UAC R307-170. Quarterly cylinder gas audits and an annual relative accuracy test audit shall be conducted in accordance with the procedures outlined in UAC R307-170. 40 CFR 60 Methods 2, 3 and 6 shall be used to determine relative accuracy. If a new monitor is installed, an initial performance test shall be performed within 30 days of installation. The performance test shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 60, Appendix B, Performance Specification 2. Notification must be made to the Director prior to conducting the performance test. Whenever the $SO_2$ CEM is bypassed for short periods, $SO_2$ CEM data from the previous three days will be averaged and used as an emission factor to determine emissions.

The mass flow rate of the flue gas shall be determined by a volumetric flow measurement device that meets or exceeds the requirements contained in 40 CFR 60 Appendix B. An annual relative accuracy test audit shall be conducted in accordance with the procedures outlined in UAC R307-

170 and 40 CFR 60 Appendix B. If a new volumetric flow measurement device is installed, an initial performance test shall be performed within 30 days of installation. The performance test shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 52 Appendix E. Notification must be made to the Director prior to conducting the performance test.

Tesoro shall comply with a 95% recovery efficiency requirement for all periods of operation except during periods of startup, shutdown, or malfunction of the SRU/TGI/TGTU. The 95% recovery efficiency will be determined on a daily basis; however, compliance will be determined on a rolling 30-day average basis. Tesoro shall determine the percent recovery by measuring the flow rate and concentration of $H_2S$ in the feed streams going to the SRU and by measuring the $SO_2$ emissions with the CEMS at the SRU incinerator. The feed streams shall include the overhead stream from the Fuel Gas Desulfurization unit (Amine unit) regenerator and the overhead stream from the Sour Water Stripper. The flow rate will be determined continuously; the $H_2S$ concentration shall be determined at least once every three years (samples may be collected as manual grabs or through remote monitoring). The flow rate and $H_2S$ concentration values will be used to determine the daily feed rate. SRU efficiency results shall be reported to the Director a minimum of once per year.
[R307-401]

II.B.4 **Conditions on $SO_2$ Cap Sources**

II.B.4.a Combined emissions of $SO_2$ from the $SO_2$ Cap Sources shall not exceed the following limits:

November 1 through end of February: 3.699 tons/day

March 1 through October 31: 4.374 tons/day

Compliance with the daily limitation shall be determined by summing the emissions calculated in conditions II.B.4.a.1 and II.B.4.a.2 below.
[R307-401]

II.B.4.a.1 Daily $SO_2$ emissions from the ESP stack shall be determined by multiplying the sulfur dioxide concentration in the flue gas by the mass flow of the flue gas.

The $SO_2$ concentration in the flue gas shall be determined by a CEM that meets or exceeds the requirements contained in 40 CFR 60, Appendix B, Performance Specification 2. The monitor span shall be 350 ppm. Daily zero (0-20% of span value) and span (50-100% of span value) calibration drift tests shall be conducted in accordance with 40 CFR 60, Appendix F and UAC R307-170. Quarterly cylinder gas audits and an annual relative accuracy test audit shall be conducted in accordance with 40 CFR 60 Appendix F and UAC R307-170. 40 CFR 60 Methods 2, 3 and 6 shall be used to determine relative accuracy. If a new $SO_2$ monitor is installed, an initial performance test shall be performed within 30 days of installation. The performance test shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 60, Appendix B, Performance Specification 2. Notification must be made to the Director prior to conducting the performance test. Whenever the $SO_2$ CEM is unavailable for short periods (i.e. CO boiler or ESP emergency bypass, FCCU start-up and shutdowns), $SO_2$ CEM data from the previous three days will be averaged and used as an emission factor to determine emissions from the FCCU.

The mass flow rate of the flue gas shall be determined by a volumetric flow measurement device that meets or exceeds the requirements contained in 40 CFR 60 Appendix B. An annual relative accuracy test audit shall be conducted in accordance with the procedures outlined in UAC R307-170 and 40 CFR 60 Appendix B. If a new volumetric flow measurement device is installed, an initial performance test shall be performed within 30 days of installation. The performance test shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 52 Appendix E. Notification must be made to the Director prior to conducting the performance test.

$SO_2$ emissions from the FCCU regenerator shall be calculated by subtracting the emissions attributable to the CO Boiler from the mass ESP emissions. Emissions attributable to combustion of plant gas in the CO Boiler shall be calculated by multiplying the quantity of fuel used in the CO boiler by the emission factor for plant gas as determined below.
[R307-401]

II.B.4.a.2 Daily $SO_2$ emissions from other affected units shall be determined by multiplying the quantity of each fuel used daily (24 hour usage) at each affected unit by the appropriate emission factor below. The values shall be summed to show the total daily $SO_2$ emission.

Emission factors (EF) for the various fuels shall be as follows:

Natural gas: EF = 0.60 lb/MMscf
Propane: EF = 0.60 lb/MMscf
Plant fuel gas: the emission factor shall be calculated from the $H_2S$ measurement or from the $SO_2$ measurement obtained in section II.B.4.g of this permit. The emission factor, where appropriate, shall be calculated as follows:

EF (lb $SO_2$/MMscf gas) = [(24 hr avg. ppmdv $H_2S$) /10^6] [(64 lb $SO_2$/lb mole)] [(10^6 scf/MMscf)/(379 scf/lb mole)]

Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel.
[R307-401]

II.B.4.b Emissions of $SO_2$ from the permitted source shall not exceed 1,637 tons per rolling 12-month period. The $SO_x$ limit at the FCCU is 705 tons per rolling 12-month period.

Compliance shall be determined on a 12-month rolling average. Within 20 days of the beginning of each calendar month, the $SO_2$ emission totals calculated to demonstrate compliance with the daily (24-hr) limitations shall be totaled for the previous month. The monthly total shall be added to the totals from the previous 11 months to determine the new 12-month rolling total.
[R307-401]

II.B.4.c The $SO_x$ emissions from the FCCU regenerator shall not exceed 9.8 lbs/1000 lbs coke burned, based on a seven-day average.

The following monitoring protocol has been approved by EPA staff in accordance with 40 CFR 60.106(i)(12), in letters from EPA dated August 29, 1997, May 12, 2003, June 20, 2005 and August 8, 2008, and may not be modified without prior EPA approval.
[40 CFR 60]

II.B.4.c.1 Each day, the daily $SO_x$ emissions from the FCCU regenerator, as calculated below, shall be multiplied by a factor of 1.05 and divided by the amount of coke burned in the FCCU regenerator during the same period. The result shall be added to the calculated values for the previous six days and the total divided by seven to determine the seven-day average.

The weight of coke burned in the FCCU regenerator shall be determined by a mass balance calculation utilizing the measured airflow to the regenerator, and the volume percent CO and $O_2$ measured in the regenerator flue gas, in accordance with the procedure documented in correspondence to the DAQ dated November 3, 1995.

This monitoring method is valid only if the following process conditions and procedures are met.

(a) Sulfur content of the feed to the FCCU is not greater than 0.85 wt%, based on a seven-day average.

The sulfur content of the feed shall be determined by obtaining and analyzing a minimum of three grab-samples per seven-day period.

(b) Temperature of the FCCU regenerator is between 1182º Fahrenheit and 1419º Fahrenheit, based on an 8-hour average.

The temperature of the FCCU regenerator shall be determined using a suitable temperature-sensing device. The device shall be calibrated according to manufacturer's specifications.

(c) The oxygen concentration in the FCCU regenerator is less than or equal to 3.4 % by volume, based on an 8-hour average.

A CEM shall be used to determine the oxygen concentration in the regenerator flue gas. The monitor shall meet or exceed the requirements specified in 40 CFR 60, Appendix B, and Performance Specification 3. The monitor span shall be 1.5-2.0 times the allowable level. Daily zero (0-20% of span value) and span (50-100% of span value) calibration drift tests shall be conducted in accordance with UAC R307-170. Quarterly cylinder gas audits and an annual relative accuracy test audit shall be conducted in accordance with the procedures outlined in UAC R307-170. 40 CFR 60 Method 3B shall be used to determine relative accuracy. If a new monitor is installed, an initial performance test shall be performed within 30 days of installation. The performance test shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 60, Appendix B, and Performance Specification 3. Notification must be made to the Director prior to conducting the performance test.

(d) The CO concentration in the FCCU regenerator is less than or equal to 4.4% by volume based on an 8-hour average.

A CEM shall be used to determine the CO concentration in the regenerator flue gas. The monitor shall meet or exceed the requirements specified in 40 CFR 60, Appendix B, and Performance Specification 4, and 40 CFR 60, Appendix F. The monitor span shall be 1.5-2.0 times the allowable level. Daily zero (0-20% of span value) and span (50-100% of span value) calibration drift tests shall be conducted in accordance with UAC R307-170. Quarterly cylinder gas audits and an annual relative accuracy test audit shall be conducted in accordance with the procedures outlined in UAC R307-170. 40 CFR 60 Method 10 or 10A shall be used to determine relative accuracy. If a new monitor is installed, an initial performance test shall be performed within 30 days of installation. The performance test shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 60, Appendix B, and Performance Specification 4. Notification must be made to the Director prior to conducting the performance test.

(e) The CO emissions to the atmosphere from the FCCU ESP shall not exceed 500 ppm by volume per 40 CFR 60.103(a).

A CEM shall be used to determine the CO concentration in the ESP flue gas. The monitor shall meet or exceed the requirements specified in 40 CFR 60, Appendix B, and Performance Specification 4, and 40 CFR 60, Appendix F. The monitor span shall be 1000 ppm as specified in 40 CFR 60 Subpart J 60.105. Daily zero (0-20% of span value) and span (50-100% of span value) calibration drift tests shall be conducted in accordance with UAC R307-170. Quarterly cylinder gas audits and an annual relative accuracy test audit shall be conducted in accordance with the procedures outlined in UAC R307-170. 40 CFR 60 Method 10 shall be used to determine relative accuracy. If a new monitor is installed, an initial performance test shall be performed within 30 days of installation. The performance test shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 60, Appendix B, and Performance Specification 4. Notification must be made to the Director prior to conducting the performance test.

If Tesoro intentionally changes the FCCU's operating parameters (FCCU's feed sulfur content, the regenerator temperature, the regenerator oxygen concentration, or the regenerator CO concentration) to a value outside the listed ranges, compliance with the sulfur oxides limitation shall be demonstrated in accordance with 40 CFR 60.106(i). Performance of such compliance demonstrations shall begin within two weeks of first recording the change in operating parameters.

Tesoro may then conduct performance tests as required to establish a new set of parameters for the above alternate monitoring procedure, in accordance with 40 CFR 60.106(i)(12). Tesoro must submit the new parameters and associated test data for approval by the EPA before use.

An unintentional variation of any of the operating parameters associated with this monitoring method beyond the range allowed by this method shall constitute a violation of this monitoring condition, unless the variation can be positively identified as the result of an unavoidable breakdown.
[R307-401]

II.B.4.d The following information shall be maintained and made available upon request:

1. The monitoring record of the lbs $SO_x$ /1000 lb coke burned
2. Results of the sulfur analysis of the feed, including sample dates, times, and sulfur

concentration
3. The monitoring record of the temperature sensor, the date of each calibration of the sensor and any corrective actions required or performed
4. The monitoring record of the oxygen CEM and any calibration or maintenance activity on the monitor
5. The monitoring record of the CO CEM and any calibration or maintenance activity on the monitor
6. The date, time, and description of any change in the listed FCCU operating parameters, whether or not such change was intentional
7. All information associated with the performance of 40 CFR 60.106(i)(12), Compliance Demonstration, if such demonstration is performed
[R307-401]

II.B.4.e If any of the listed operating parameters are intentionally changed, Tesoro shall submit written notification of the change and confirmation of the initiation of the 40 CFR 60.106(i)(12), Compliance Demonstration, within 14 days of first recording the change. The notification shall be submitted to the Director and to EPA.

If any of the listed operating parameters are unintentionally exceeded, Tesoro shall submit a report of the exceedance to the Director on the next quarterly monitoring report. The report shall include a description of the exceedance, an estimate of any excess emissions, the time of the exceedance, and the actions taken to correct the situation.
[R307-401]

II.B.4.f The following sources shall not be regulated for $SO_2$ or $NO_x$ emissions nor shall they be included in the emission limitation totals herein:

1. North flare (FCCU/VRU/GHT/Alky Flare)
2. South flare (Crude/UFU/DDU Flare)

[R307-401]

II.B.4.g The $H_2S$ content of fuel gas combusted at any affected unit shall not exceed 0.10 grains $H_2S$/dscf (162 ppmdv), based on a rolling three-hour average (calculated as the arithmetic average of three contiguous 1-hour averages). Compliance with this limitation shall be determined as follows:

1. For natural gas, compliance is assumed while the fuel comes from a public utility.

2. For plant gas, the $H_2S$ content of the fuel gas shall be measured with a CMS that meets or exceeds the requirements contained in 40 CFR 60, Appendix B, Specification 7. The monitor shall be installed in a location representative of the $H_2S$ content in the fuel gas system. The location shall be approved in writing by the Director prior to installation. The current approved location of the $H_2S$ monitor is on the outlet of fuel-gas blending vessel V-917. The span of the monitor shall be 300 ppm. Daily zero (0-20% of span value) and span (50-100% of span value) calibration drift tests shall be conducted in accordance with 40 CFR 60 Appendix F and UAC R307-170. Quarterly cylinder gas audits and an annual relative accuracy test audit shall be conducted in accordance with 40 CFR 60 Appendix F and UAC R307-170. 40 CFR 60 Method 11 shall be used to determine relative accuracy. If a new monitor is installed, an initial performance test shall be performed within 30 days of installation. The performance test shall

be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 60, Appendix B, and Performance Specification 7. Notification must be made to the Director prior to conducting the performance test.

If the monitor reading is not available, the refinery fuel gas shall be sampled as close to the monitor location as safely possible at least once each day. The sample shall be analyzed for sulfur content with a detection tube capable of reading the required concentration limit.

3. In lieu of the $H_2S$ CMS in paragraph II.B.4.g.2 above, for fuel gas combustion devices an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of $SO_2$ emissions into the atmosphere may be used. The monitor shall meet the requirements of 40 CFR 60.105.
[R307-401]

II.B.4.h T-104 shall be a fixed-roof vessel with closed vent controls. The tank shall have a closed-vent system with nitrogen purge, and shall vent gases released to the TGI/TGTU or to the Sour Water Stripper/SRU flare when the TGI/TGTU is not operational. The tank shall comply with 40 CFR 60 Subpart Kb. [R307-401]

II.B.5 **<u>Conditions on $NO_x$ Cap Sources</u>**

II.B.5.a Combined emissions of $NO_x$ from the $NO_x$ Cap Sources shall be no greater than 1.988 tons/day.

Compliance shall be determined daily by multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each fuel combusted at each affected unit by the associated emission factor listed below, and summing the results. The sources, fuels, and associated emission factors for this limitation are as follows:

| Sources included in emission cap | Fuel | $NO_x$ Emission factor |
|---|---|---|
| Crude Unit Furnace (H-101) | Plant Gas | results of last stack test |
| Ultraformer Furnace (F1) | Plant Gas | results of last stack test |
| Regenerator Gas Heater (F15) | Plant Gas | 81 lb/MMscf |
| FCCU/CO Boiler (ESP) | FCU Coke & plant gas | $NO_x$ CEM |
| DDU charge heater (F-680) | Plant gas | 0.049 lb/MMBtu |
| DDU rerun reboiler (F-681) | Plant gas | 0.052 lb/MMBtu |
| Cogeneration facility | Plant & natural gas | results of last stack test |
| GHT heater (F-701) | Plant gas | 0.074 lb/MMBtu |
| Hydrogen Compressors (K1s) | Propane/natural gas | 1.8 lb/hr |

The Crude Unit stack (H-101) shall be tested every year to determine the correct emission factor for the calculations above.

The UFU stack (F1) emissions shall be stack tested every year to determine the correct emission factor for the calculations above.

The initial stack tests were done on the DDU to verify the design emission factor of 0.04 lb/MMBtu for $NO_x$. The new emission factors for the DDU, computed from the results of the stack tests, are 0.049 lb/MMBtu and 0.052 lb/MMBtu as specified in the above table.

Subsequent testing shall be done if directed by the Director.

Both trains in the cogeneration facility were stack tested within 180 days of startup to show emissions equivalency of the trains. Subsequently, both trains shall be tested either simultaneously or seriatim at least once every two years.

The GHT heater was stack tested within 180 days of startup. Subsequent testing shall be done if directed by the Director.

All other units in the above list shall be stack-tested if directed by the Director. Tesoro may also perform a stack test on any of the above listed sources to provide information for updating the emission factors listed.

All stack tests shall conform to the following:

The applicant shall provide a notification of the test date at least 45 days prior to the test. A pretest conference between the owner/operator, the tester, and the Director shall be held at least 30 days prior to the test if directed by the Director.

The emission point shall conform to the requirements of 40 CFR 60, Appendix A, Method 1. Occupational Safety and Health Administration (OSHA) approved access shall be provided to the test location.

40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, or 7E shall be used to determine the $NO_x$ emission rate.

40 CFR 60, Appendix A, Method 2 shall be used to determine the volumetric flow rate.
To determine mass emission rates (lbs/hr, etc.), the pollutant concentration, as determined by the appropriate methods above, shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Director to give the results in the specified units of the emission limitation.

A $NO_x$ CEM shall be used to calculate daily $NO_x$ emissions from the FCCU/CO Boiler (ESP). Emissions shall be determined by multiplying the nitrogen dioxide concentration in the flue gas by the mass flow of the flue gas.

The $NO_x$ concentration in the flue gas shall be determined by a CEM that meets or exceeds the requirements contained in 40 CFR 60, Appendix B, Performance Specification 2. Daily zero (0-20% of span value) and span (50-100% of span value) calibration drift tests shall be conducted in accordance with UAC R307-170. Quarterly cylinder gas audits and an annual relative accuracy test audit shall be conducted in accordance with the procedures outlined in UAC R307-170. 40 CFR 60 Methods 2, 3 and 7 shall be used to determine relative accuracy. If a new monitor is installed, an initial performance test shall be performed within 30 days of installation. The performance test shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 60, Appendix B, Performance Specification 2. Notification must be made to the Director prior to conducting the performance test. Whenever the $NO_x$ CEM is bypassed for short periods, $NO_x$ CEM data from the previous three days will be averaged and used as an emission factor to determine emissions.

The mass flow rate of the flue gas shall be determined by a volumetric flow measurement device

that meets or exceeds the requirements contained in 40 CFR 60 Appendix B. An annual relative accuracy test audit shall be conducted in accordance with the procedures outlined in UAC R307-170 and 40 CFR 60 Appendix B. If a new volumetric flow measurement device is installed, an initial performance test shall be performed within 30 days of installation. The performance test shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 60 Appendix B. Notification must be made to the Director prior to conducting the performance test.
[R307-401]

II.B.5.b Emissions of $NO_x$ from the sources listed under the $NO_x$ cap shall be no greater than 598 tons per rolling 12-month period. The $NO_x$ limit at the FCCU is 174 tons per rolling 12-month period.

Compliance shall be determined on a 12-month rolling average. By the 20th day of each month, the $NO_x$ emissions calculated to show compliance with the daily limitations for the previous month shall be summed to give a monthly emission total. This shall be added to the previous 11 months' emission totals to give the new 12-month rolling total.
[R307-401]

II.B.5.c Emissions of $NO_x$ from each K1 compressor shall be no greater than 3.20 lb/hr or 933 ppmdv @10% oxygen and 400º F.

Compliance shall be determined by stack testing in accordance with the procedure for stack testing other $NO_x$ sources as described above. Testing shall be done if directed by the Director.

The maximum fired heat capacity at H-101will be no greater than 174 MMbtu/hr(LHV) based on a 1-hour average. Orifice plate will be installed to limit fuel gas pressure to 20 psi such that maximum firing rate of the burner remains unchanged.
[R307-401]

II.B.6 **Conditions on $PM_{10}$ Cap Sources**

II.B.6.a Combined emissions of filterable $PM_{10}$ from the $PM_{10}$ Cap Sources shall be no greater than 522 lbs/day. The filterable $PM_{10}$ limit at the FCCU is 69 tons per rolling 12-month period.

Compliance shall be determined daily by multiplying the quantity of each fuel combusted at the affected units by the associated emission factor for that fuel, and summing the results. The emission factors for this limitation are as follows:

| | |
|---|---|
| Natural gas: | 5 lb/MMscf |
| Plant gas: | 5 lb/MMscf |
| Cat Coke: | results of last stack test |
| Propane: | negligible |

The FCCU/COB stack (ESP) shall be stack tested every year to determine the correct emission factor for the calculations above. All other units in the above list shall be stack-tested if directed by the Director. The permitted source may also perform a stack test to provide information for updating the emission factors listed above. All stack tests shall conform to the following:

The applicant shall provide a notification of the test date at least 45 days prior to the test. A pretest conference between the owner/operator, the tester, and the Director shall be held at least 30 days prior to the test if directed by the Director.

The emission point shall conform to the requirements of 40 CFR 60, Appendix A, Method 1. OSHA approved access shall be provided to the test location. The throughput rate during compliance testing shall be no less than 90% of the rated throughput, or 90% of the highest monthly throughput achieved in the previous three years, whichever is least.

40 CFR 51, Appendix M, Methods 201 or 201a shall be used to determine front-half $PM_{10}$ emissions in stacks in which no liquid drops are present. 40 CFR 51, Appendix M, Method 202 shall be used to determine back half condensable in such stacks.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5a, 5d, or 5e as appropriate. The back half condensables shall also be tested using Method 202. All particulate captured in the back half shall be considered $PM_{10}$. For purposes of the $PM_{10}$ SIP Cap, the back half condensables shall not be used for compliance demonstration but shall be used for inventory purposes.

40 CFR 60, Appendix A, Method 2 shall be used to determine the volumetric flow rate.

To determine mass emission rates (lbs/hr, etc.), the pollutant concentration, as determined by the appropriate methods above, shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Director to give the results in the specified units of the emission limitation.
[R307-401]

II.B.7 **<u>Conditions on Tanks</u>**

II.B.7.a For the primary seals, the accumulated area of gaps between the tank wall and the metallic shoe seal or the liquid-mounted seal shall not exceed 10 square inches per foot of tank diameter. The width of any portion of any gap shall not exceed one and one half (1½) inches. If the seal is a vapor mounted seal, the accumulated area of gaps between the tank wall and seal shall not exceed one (1) square inch per foot of tank diameter, and the width of any portion of any gap shall not exceed one-half (½) inch. This condition applies to Tanks 190, 242, 243, 244, 245, 246, 247, 308, 309, 326, and 330. [R307-327]

II.B.7.b Tanks 246 and 247 shall be used only to store heavy distillate products with a True Vapor Pressure (TVP) of less than 1.5 psia, such as Jet A fuel. [R307-401-8]

II.B.7.c For the secondary seals, the accumulated area of gaps between the tank wall and the secondary seal shall not exceed one square inch per foot of tank diameter and the width of any portion of any gap shall not exceed one-half inch. This condition applies to Tanks 190, 242, 243, 244, 245, 308, 309, 326, and 330. This condition does not apply to Tanks 246 and 247.

The secondary seals shall be properly installed and maintained according to the manufacturer's recommendations.
[R307-327]

II.B.7.d The owner/operator shall comply with all applicable parts of R307-327 - Petroleum Liquid Storage. [R307-327]

## Section III: APPLICABLE FEDERAL REQUIREMENTS

In addition to the requirements of this AO, all applicable provisions of the following federal programs have been found to apply to this installation. This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including UAC R307.

NSPS (Part 60), A: General Provisions
NSPS (Part 60), Db: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
NSPS (Part 60), J: Standards of Performance for Petroleum Refineries
NSPS (Part 60), Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007
NSPS (Part 60), K: Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978
NSPS (Part 60), Ka: Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984
NSPS (Part 60), Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984
NSPS (Part 60), GG: Standards of Performance for Stationary Gas Turbines
NSPS (Part 60), XX: Standards of Performance for Bulk Gasoline Terminals
NSPS (Part 60), GGG: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006
NSPS (Part 60), GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006
NSPS (Part 60), NNN: Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations
NSPS (Part 60), QQQ: Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems
NESHAP (Part 61), A: General Provisions
NESHAP (Part 61), M: National Emission Standard for Asbestos
NESHAP (Part 61), FF: National Emission Standard for Benzene Waste Operations
MACT (Part 63), A: General Provisions
MACT (Part 63), CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries
MACT (Part 63), UUU: National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units
MACT (Part 63), EEEE: National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)
MACT (Part 63), DDDDD: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters
Title V (Part 70) major source

## REVIEWER COMMENTS

The AO will be based on the following documents:

| | |
|---|---|
| Is Derived From | Source Submitted NOI dated November 29, 2012 |
| Incorporates | Additional Information Submitted dated February 5, 2013 |
| Supersedes | DAQE-AN103350058B-13 dated February 12, 2013 |

1. Comment regarding Emission total clarification:
   Tesoro's Salt Lake Refinery is listed in the $PM_{10}$ SIP. That document establishes emission caps for three (3) pollutants, specifically $PM_{10}$ at 95.3 tons/yr (daily limit times 365), $NO_x$ at 598 tons/yr and $SO_2$ at 1637 tons/yr. With the exception of $SO_2$ which is for the entire refinery (not including the North and South Flares), these caps are established for certain subsets of the emitting equipment at the refinery. The emission totals included in this engineering review are an estimate of the total PTE from all the refinery equipment - both under and outside the emission caps. The Tesoro Salt Lake Refinery acknowledges its status as a GHG major source.

   [Last updated May 1, 2013]

2. Comment regarding Particulate condensable emissions:
   As stated previously, Tesoro's Salt Lake Refinery is listed in the $PM_{10}$ SIP. That document established several emission limitations, one of which is a cap on $PM_{10}$ emissions. At the time the SIP was written, the cap on $PM_{10}$ emissions was established using only the filterable $PM_{10}$ emissions captured during stack testing. This limitation was then included in the AO (and subsequent revisions) issued to Tesoro.

   UDAQ has since agreed that all future particulate ($PM_{10}$ and $PM_{2.5}$) limitations at all sources will also include the condensable fraction of particulate emissions (such as those found in the back half of a particulate sampling train or by reference test method 202). However, any limitation which is derived directly from the $PM_{10}$ SIP cannot be altered without similarly altering the SIP. Therefore, those limitations on SIP-listed sources will continue to retain the original "filterable emissions only" language, with the condensable emissions being used only for inventory purposes. Such is the case with Tesoro's $PM_{10}$ cap emission limit.

   It is the intent of the Division to update these types of conditions once new SIP limitations are established in the $PM_{2.5}$ SIP. [Last updated May 1, 2013]

3. Comment regarding Non-modified sources:
   Several emission units are specifically affected by this project but are not considered modified. Each is addressed below:

   GHT Reactor Charge Heater (F-701) - this unit will increase firing by 3.1 MMBtu/hr on an annual average basis. The unit has no limitation on firing rate in any current permit condition or regulatory requirement, and no physical modification is required for the unit to increase firing rate. Therefore, the unit is currently capable of operating at this rate. The unit will burn the same fuel following completion of the project. DAQ does not interpret this increase in firing rate to represent a change in the method of operation of this unit.

Sulfur Recovery Unit (SRU) - this unit will receive an increase in sulfur loading from increased utilization of the DDU and the change in feed at the GHT from HCN to light diesel. The overall sulfur loading will increase by approximately 470 lb/day. The SRU is sized to handle this sulfur loading, and was designed to process and remove sulfur from these process streams. This increase requires no physical changes at the SRU and does not represent a change in the method of operation of the SRU.

Distillate Desulfurization Unit (DDU) Charge Heater (F-680) - this unit will increase firing by 0.97 MMBtu/hr when operating in KHT mode. Additional light diesel is created during the KHT process which is then routed to the DDU to reduce sulfur content. As with heater F-701, no physical change is required, and no permit or regulatory limitation currently exists on firing rate. Therefore, no change in the method of operation of this unit will take place.

Storage Tanks (TKs-204, 212, 213, 246, 247) - several storage tanks will increase throughput. These tanks are not currently limited in throughput by permit term or regulatory requirement and no physical change is required. No changes in service will occur.

Loading Rack - while additional jet kerosene and distillate fuel oil #2 products will be loaded through the loading rack, there are currently no permit or regulatory limitations on these products and no physical changes are required at the loading racks to accommodate the additional throughput. [Last updated May 15, 2013]

4. Comment regarding Modified sources:
Those emission units which are being modified consist of additional piping (with associated valves, flanges and the like) and a pump (needed because of lower tower pressure when operating in KHT mode). These constitute fugitive emission sources which are included in Tesoro's LDAR program for VOC emission minimization. [Last updated May 1, 2013]

5. Comment regarding Relationship to Waxy Crude Project:
DAQ has considered this project in relation to other recently permitted projects at the Tesoro refinery, including the recent "Waxy Crude" project, including whether the projects need to be aggregated for purposes of NSR review.

When making consideration of one or more projects as a single physical change, reviewers often cite EPA's opinion letter to 3M (the 3M-Maplewood Memo) as laying out the usual criteria for evaluation. These criteria are aimed at evaluating the source's intent behind the projects and how closely the projects are tied economically and/or operationally. In this instance DAQ analyzed the following information regarding this project and the previously approved Waxy Crude project:

1. Although the two projects were developed during a similar timeframe, the application for the Waxy Crude project was submitted in 2011. At no point during the processing of the Waxy Crude project did DAQ need any information contained in this project, and the Waxy Crude project was completed and fully permitted prior to receipt of the NOI for this project.

2. The projects do not appear to be technically or economically related or dependent on each other in any way. Each project affects different process units. The Waxy Crude project did not involve any physical changes to the GHT unit, while this project affects only the GHT unit. While each project may have subsequent related downstream effects such as additional sulfur loading to the SRU, these effects are ancillary and do not demonstrate interdependence.

3. Operation of the GHT in KHT mode does not have an impact on the refinery's ability to handle or process waxy crudes.

Therefore, DAQ submits that these two projects are separate and not related. They are not aggregated and do not constitute a single project for purposes of NSR. A similar analysis was performed against other previously approved projects. These projects were all found to be well outside of the "short time period" used in the 3M-Maplewood Memo and no realistic argument could be raised to even consider these older projects somehow related to this GHT-KHT project. [Last updated May 15, 2013]

6. Comment regarding Federal Requirements:
While the Tesoro refinery is subject to several federal requirements (NSPS, NESHAP and MACT), no new applicable requirements are triggered by this particular project. Specifics are dicsussed below:

40 CFR 60 Subpart Kb - none of the storage tanks being affected by this project are being reconstructed or modified.

40 CFR 60 Subpart GGGa - it is not expected that the total number of components being added or replaced will constitute a construction, reconstruction, or modification under 40 CFR 60.14. Therefore,Subpart GGGa does not apply to the components associated with this project.

Other NSPS subparts (A, Db, J, Ja, K, Ka, GG, GGG, NNN, and QQQ are not affected by this project)

40 CFR 61 subparts (A, M, FF) and 63 subparts (CC, UUU, EEEE, DDDDD) are not affected by this project.

Tesoro will continue to comply with all applicable requirements and standards of these rules. [Last updated May 15, 2013]

7. Comment regarding PSD and NSR:
This project is classified as a minor modification under the provisions of both PSD and non-attainment NSR. The increase in actual emissions for all criteria pollutants is below the significance threshold. The increase in greenhouse gas emissions is also less than the significant emission rate. [Last updated May 1, 2013]

8. Comment regarding Offsets:
While a small increase in actual emissions is anticipated as a result of this project, there is no increase in Tesoro's permitted SIP cap allowables. Therefore no offsets are required for $PM_{10}$. As this project constitutes a minor modification under federal $PM_{2.5}$ non-attainment NSR regulations, no offsetting is required under the provisions of Appendix S to 40 CFR 51. Finally, Tesoro is not increasing its expected PTE of VOC nor raising its permitted SIP cap $NO_x$ limit, so no offsets are required for ozone. [Last updated May 1, 2013]

9. Comment regarding Consent Decree:
This project is not being undertaken to comply with any provisions of the Consent Decree, and while Tesoro will continue to comply with all provisions of that decree, it does not bear any

relevance to this project. [Last updated May 1, 2013]

10. Comment regarding Change in condition II.B.3.a:
When DAQ issued DAQE-AN103350058B-12, it included language for condition II.B.3.a which required Tesoro to route all gaseous emissions from the SRU through the TGTU before final treatment at the TGI. This language stemmed from public comments received during the comment process on the Waxy Crude AO and was added in DAQ's Response to Comments memo on that project.

Tesoro Refining and Marketing did not have a chance to review the language of that condition prior to issuance of the final AO and has since objected to the language. The requirement to route all SRU gases through the TGTU prevents the TGTU from ever being down for maintenance. Tesoro pointed out that it had anticipated instances where the TGTU may be offline and accounted for these increased emissions in its emission calculations submitted as a part of the original NOI for the Waxy Crude project. DAQ has since reviewed that information and agrees that Tesoro's emission calculations were correct.

Therefore, condition II.B.3.a will be amended to read as follows:

Tesoro shall install a TGTU (tail gas treatment unit) at the SRU as part of the Waxy Crude Processing Project. Installation of the TGTU shall be complete prior to the resumption of normal operations as outlined in conditions I.5 and I.7. Gaseous emissions from the SRU shall be treated by the TGTU during normal operations prior to final treatment at the TGI. [Last updated May 15, 2013]

## ACRONYMS

The following lists commonly used acronyms and associated translations as they apply to this document:

| | |
|---|---|
| 40 CFR | Title 40 of the Code of Federal Regulations |
| AO | Approval Order |
| BACT | Best Available Control Technology |
| CAA | Clean Air Act |
| CAAA | Clean Air Act Amendments |
| CDS | Classification Data System (used by EPA to classify sources by size/type) |
| CEM | Continuous emissions monitor |
| CEMS | Continuous emissions monitoring system |
| CFR | Code of Federal Regulations |
| CMS | Continuous monitoring system |
| CO | Carbon monoxide |
| $CO_2$ | Carbon Dioxide |
| $CO_2e$ | Carbon Dioxide Equivalent - 40 CFR Part 98, Subpart A, Table A-1 |
| COM | Continuous opacity monitor |
| DAQ | Division of Air Quality (typically interchangeable with UDAQ) |
| DAQE | This is a document tracking code for internal UDAQ use |
| EPA | Environmental Protection Agency |
| FDCP | Fugitive dust control plan |
| GHG | Greenhouse Gas(es) - 40 CFR 52.21 (b)(49)(i) |
| GWP | Global Warming Potential - 40 CFR Part 86.1818-12(a) |
| HAP or HAPs | Hazardous air pollutant(s) |
| ITA | Intent to Approve |
| LB/HR | Pounds per hour |
| MACT | Maximum Achievable Control Technology |
| MMBTU | Million British Thermal Units |
| NAA | Nonattainment Area |
| NAAQS | National Ambient Air Quality Standards |
| NESHAP | National Emission Standards for Hazardous Air Pollutants |
| NOI | Notice of Intent |
| $NO_x$ | Oxides of nitrogen |
| NSPS | New Source Performance Standard |
| NSR | New Source Review |
| $PM_{10}$ | Particulate matter less than 10 microns in size |
| $PM_{2.5}$ | Particulate matter less than 2.5 microns in size |
| PSD | Prevention of Significant Deterioration |
| PTE | Potential to Emit |
| R307 | Rules Series 307 |
| R307-401 | Rules Series 307 - Section 401 |
| $SO_2$ | Sulfur dioxide |
| Title IV | Title IV of the Clean Air Act |
| Title V | Title V of the Clean Air Act |
| TPY | Tons per year |
| UAC | Utah Administrative Code |
| UDAQ | Utah Division of Air Quality (typically interchangeable with DAQ) |
| VOC | Volatile organic compounds |